GOVERNMENT OF BRITISH COLUMBIA

British Columbia Montney
Supply Study and Type Curve Analysis

McDANIEL

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Prepared For:

Government of British Columbia
Ministry of Energy, Mines and Petroleum Resources
Economics and Market Development Branch,
Oil and Gas Division
5th Floor, 1810 Blanshard Street
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November 8, 2019

Government of British Columbia
Ministry of Energy, Mines and Petroleum Resources
Economics and Market Development Branch, Oil and Gas Division
5th Floor, 1810 Blanshard Street
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Attention: Mr. Curtis Kitchen, P. Eng., Chief Engineer and Director of Royalties, Economics and Market Development Branch
Oil and Gas Division, Ministry of Energy, Mines and Petroleum Resources

Reference: **British Columbia Montney Supply Study and Type Curve Analysis**

Dear Sir:

Pursuant to your request, McDaniel & Associates Consultants Ltd. (McDaniel) has prepared an estimate of total resource potential for the Montney Formation within British Columbia for Her Majesty the Queen in Right of the Province of British Columbia, as represented by the Ministry of Energy, Mines and Petroleum Resources, Oil and Gas Division, hereinafter referred to as the "Company", as of December 31, 2018. Resource potential has been predicated on a long-term AECO gas price of $3.00/MMBtu and operating and capital cost structures that are representative of current market conditions for commercial Montney operations that are being developed with pad drilling and long-term marketing agreements.

PURPOSE

The purpose of this study was to predict future supply and development in the Montney Formation of British Columbia. Future supply estimates are predicated on key geological characteristics such as interval thickness, porosity, pressure gradient and water saturation coupled with analysis of current producing wells and recent completion trends.

The Heritage and Northern Montney regions have been divided into 24 areas to provide an overview of performance variances due to geographical location and liquids content. The maps in figures 1 and 2 below shows the areas as defined by the Company.

Figure 1: Regional Map – Heritage Montney

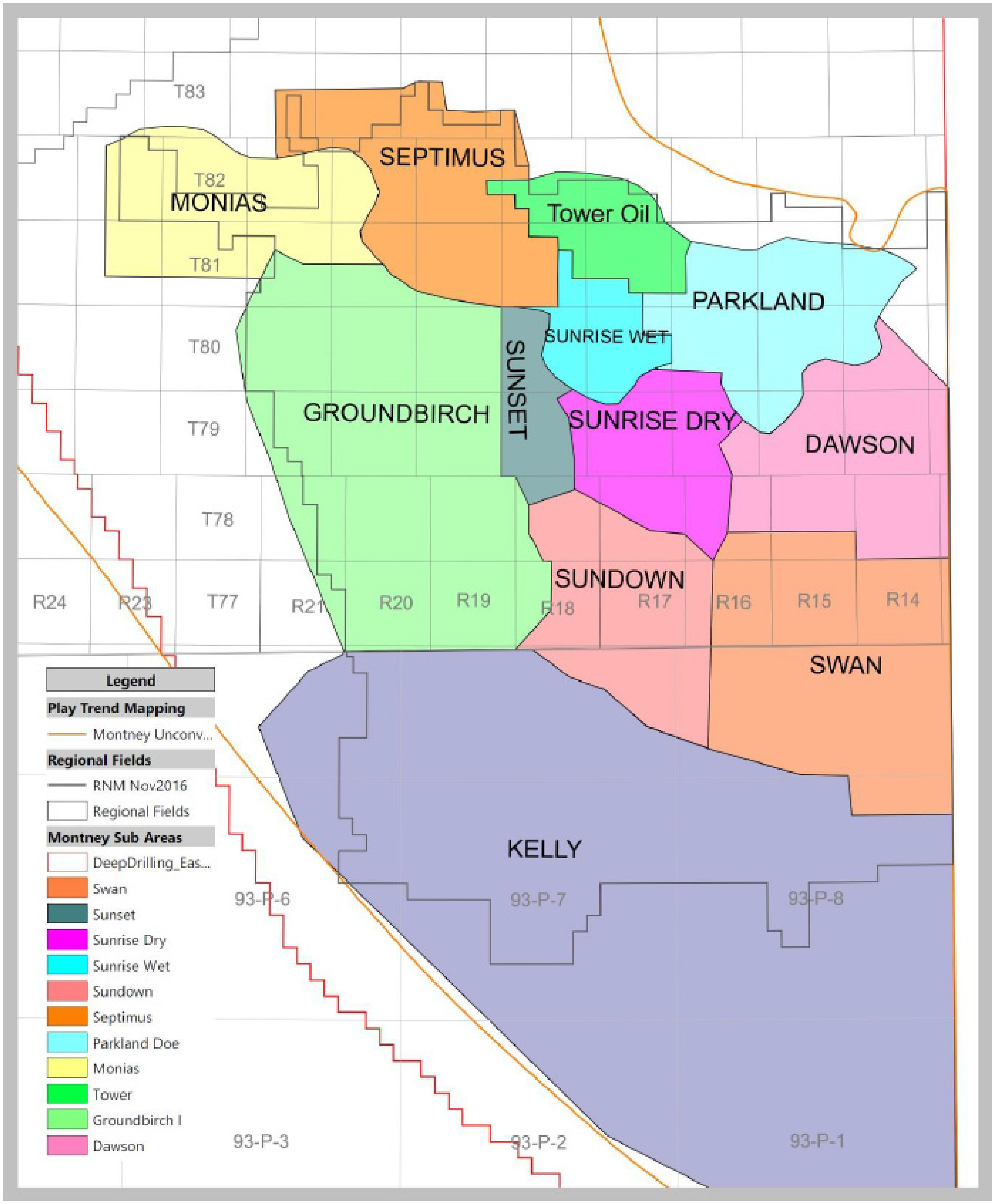
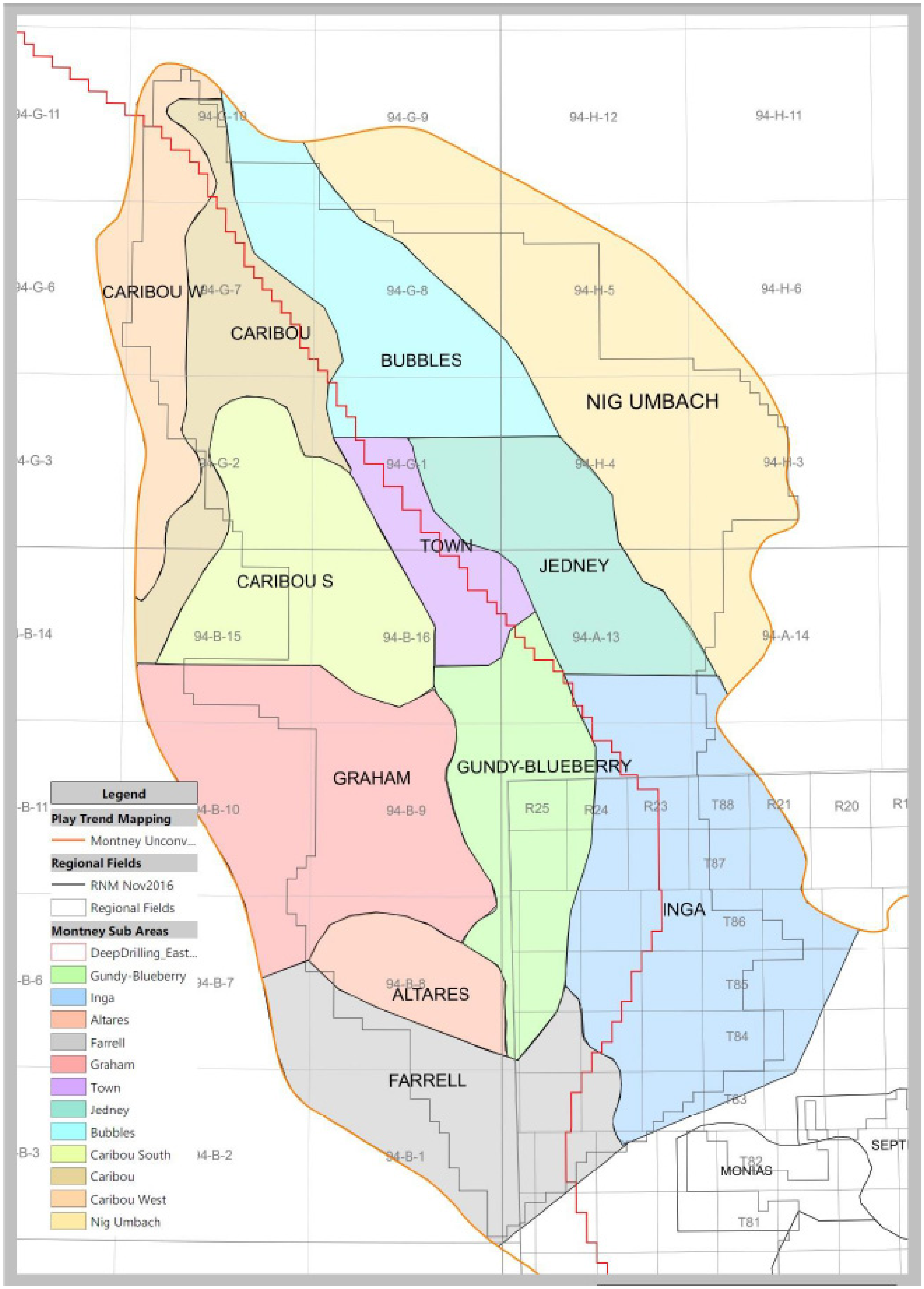


Figure 2: Regional Map – Northern Montney



It should be noted that the Caribou, Caribou West, Farrell, Groundbirch, Gundy, and Jedney areas were further sub-divided based on reservoir quality variations noted during the analysis. A map outlining the revised boundaries is presented within the appendices.

The supply estimates will assist the Company with the creation of Montney development scenarios that include estimates of short, medium and long-term activity by stratigraphic zone and subarea.

The assessment will also assist the Company in making predictions of future natural gas, condensate, oil and natural gas liquid (NGL) production at various supply costs.

Supply estimates were predicated on a combination of decline analysis, volumetric analysis, visual analytics and Machine Learning analysis.

EXECUTIVE SUMMARY

Type curves and remaining inventory were created for 24 areas in the Montney within the Province of British Columbia as defined by the Company. Within each area, the Montney was further sub-divided by its stratigraphic zone i.e. Upper, Middle or Lower Montney.

Type curves were based on non-confidential production data and geological parameters such as porosity, pay thickness, pressure gradient, depth and water saturation combined with an analysis of high density Montney Pad recovery factors and Machine Learning analysis. Machine Learning was used to support conventional visual analytics methods and allowed for both an assessment of completion based performance improvements and economic optimization of supply outcomes.

Future resource inventory was predicated on an AECO gas price of $3.00/MMBtu and operating and capital cost structures that are representative of current market conditions for commercial Montney operations being developed with pad drilling and long-term marketing agreements. It should be noted that operator specific circumstances have not been reflected in the supply estimates. Furthermore, lateral well spacing and length assumptions have been standardized in order to provide a reasonable, consistent approach across all regions and stratigraphic zones. Standardized spacing and length assumptions have been based on recent industry trends and economic optimization at the well level.

Supply potential has been further separated into higher confidence “discovered resources” and lower confidence “undiscovered resources”. Discovered resources are those volumes that could be potentially considered either reserves or contingent resources under Canadian Oil and Gas Evaluation Handbook (COGEH) while undiscovered resources would notionally be considered prospective resources. In order to qualify as discovered resources, McDaniel assigned future inventory to be within three miles of existing productive well control in a given development bench. It should be noted that while these estimates were prepared under the general guidelines outlined in COGEH they should not be considered official compliant estimates of reserves or contingent or prospective resources. All estimates presented are shown on a Best Estimate (P_{50}) basis and have **not** been risked for technical and commercial uncertainties.

Outlined below is a summary of remaining inventory, average per well estimated ultimate recoveries (EUR), total resource potential and break-even supply cost by area and stratigraphic interval. Due to potential commercial sensitivities, area names presented in Tables 1b and 1c have been concealed.

Table 1a: British Columbia Montney Supply Summary

Region	Development Layer (U/M/L)	Discovered Remaining Inventory	Total Remaining Inventory	Discovered Undeveloped Raw Gas (Bcf)	Total Undeveloped Raw Gas (Bcf)
Heritage	Lower	2,672	3,856	29,740	42,625
	Middle	1,348	3,144	12,507	27,617
	Upper	3,090	3,671	39,638	45,852
	Combined	7,109	10,671	81,885	116,094
Northern	Lower	6,053	12,003	57,771	109,010
	Middle	4,952	11,125	42,920	91,202
	Upper	6,621	11,527	57,425	96,366
	Combined	17,626	34,655	158,116	296,577
Heritage + Northern	Lower	8,725	15,859	87,511	151,635
	Middle	6,300	14,269	55,428	118,819
	Upper	9,710	15,198	97,063	142,217
	Combined	24,735	45,326	240,002	412,672

In addition to the undeveloped volumes, Best Estimate (P_{50}) producing volumes were estimated to be 21,657 Bcf, resulting in a 434,329 Bcf total recoverable resource prior to gas shrinkage. In order to arrive at marketable volumes, a gas shrinkage of 8 percent (current provincial average) can be applied to the Raw Gas volumes, resulting in 399,583 Bcf total marketable gas.

Table 1b: British Columbia Montney Supply Summary - Heritage

Area	Development Layer (U/M/L)	Discovered Remaining Inventory	Total Remaining Inventory	Raw Gas EUR per Well (Bcf)	Discovered Undeveloped Raw Gas (Bcf)	Total Undeveloped Raw Gas (Bcf)	AECO Supply Cost ($/MMBtu)
Area 1	Lower	142	189	11.3	1,602	2,132	1.40
Area 1	Middle	90	93	13.3	1,194	1,240	1.22
Area 1	Upper	78	78	14.1	1,105	1,105	1.28
Area 2	Lower	113	248	4.1	461	1,013	1.80
Area 2	Middle	45	253	8.0	356	2,019	0.58
Area 2	Upper	304	317	9.9	3,012	3,146	0.29
Area 4	Lower	452	582	12.1	5,465	7,040	1.47
Area 4	Middle	75	307	8.9	671	2,743	1.99
Area 4	Upper	400	438	13.8	5,516	6,038	1.30
Area 7	Lower	36	230	9.7	345	2,227	1.08
Area 7	Middle	37	229	6.3	231	1,451	1.52
Area 7	Upper	166	215	10.1	1,675	2,169	1.15
Area 9	Lower	171	211	12.5	2,130	2,635	1.63
Area 9	Middle	139	278	7.6	1,050	2,105	2.46
Area 9	Upper	245	257	14.5	3,565	3,742	1.40
Area 10	Lower	406	409	6.3	2,565	2,580	1.11
Area 10	Middle	149	244	7.8	1,166	1,918	0.38
Area 10	Upper	258	326	8.4	2,174	2,746	0.32
Area 11	Lower	117	117	8.8	1,035	1,035	0.00
Area 11	Middle	89	139	7.4	659	1,028	0.00
Area 11	Upper	164	164	9.7	1,602	1,602	0.00
Area 16	Lower	192	384	15.4	2,950	5,900	1.46
Area 16	Middle	256	378	13.0	3,316	4,893	1.51
Area 16	Upper	609	610	14.5	8,853	8,870	1.44
Area 22	Lower	603	729	14.7	8,859	10,712	1.22
Area 22	Middle	244	489	9.8	2,380	4,779	1.78
Area 22	Upper	35	148	17.5	617	2,595	1.15
Area 23	Lower	162	167	18.3	2,968	3,058	0.98
Area 23	Middle	74	195	9.6	717	1,880	1.81
Area 23	Upper	335	335	19.0	6,346	6,346	0.93
Area 25	Lower	82	393	9.4	768	3,702	2.42
Area 25	Middle	64	394	7.9	506	3,133	2.49
Area 25	Upper	453	632	11.1	5,050	7,048	2.06
Area 29	Lower	197	197	3.0	591	591	0.00
Area 29	Middle	87	143	3.0	260	427	0.00
Area 29	Upper	41	148	3.0	123	445	0.00
Area 30	Lower	Sub-Economic - No Recoverable Volumes Assigned					
Area 30	Middle	Sub-Economic - No Recoverable Volumes Assigned					
Area 30	Upper	Sub-Economic - No Recoverable Volumes Assigned					

Table 1c: British Columbia Montney Supply Summary – Northern

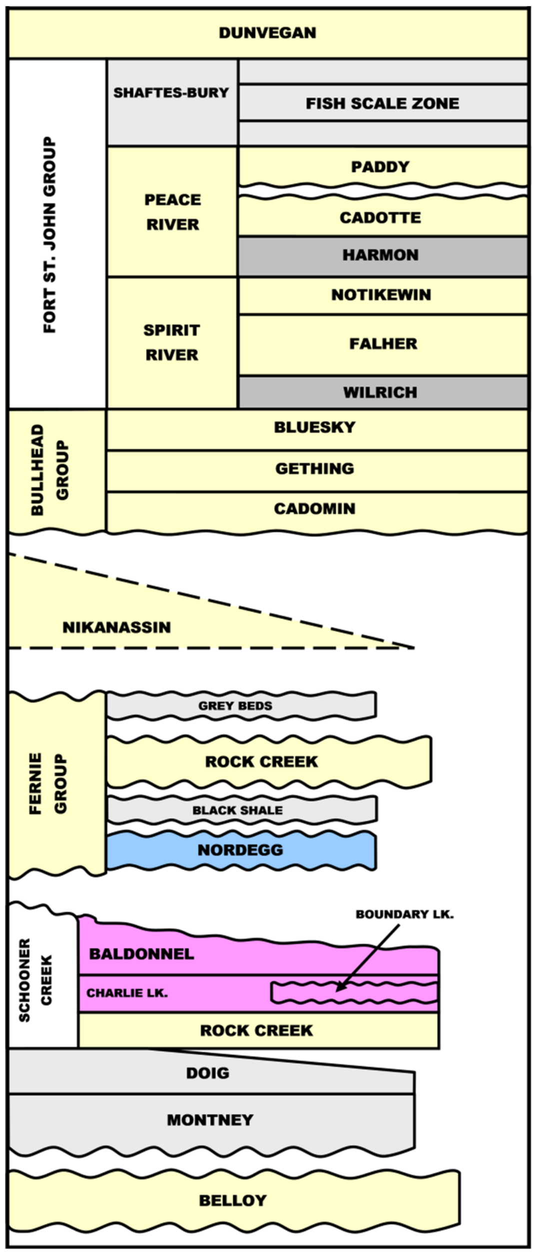
Area	Development Layer (U/M/L)	Discovered Remaining Inventory	Total Remaining Inventory	Raw Gas EUR per Well (Bcf)	Discovered Undeveloped Raw Gas (Bcf)	Total Undeveloped Raw Gas (Bcf)	AECO Supply Cost ($/MMBtu)
Area 3	Lower	55	207	8.1	443	1,664	1.98
Area 3	Middle	10	208	7.0	70	1,453	2.26
Area 3	Upper	96	413	7.8	751	3,242	2.19
Area 5	Lower	498	646	11.5	5,743	7,455	0.09
Area 5	Middle	214	313	10.7	2,298	3,358	0.24
Area 5	Upper	241	292	11.3	2,727	3,313	0.13
Area 6	Lower	249	249	13.1	3,254	3,254	0.00
Area 6	Middle	251	251	10.3	2,582	2,582	0.16
Area 6	Upper	244	249	11.2	2,727	2,788	0.25
Area 8	Lower	1075	1509	7.1	7,589	10,659	1.11
Area 8	Middle	438	766	8.4	3,683	6,440	0.78
Area 8	Upper	367	781	8.0	2,926	6,220	0.88
Area 12	Lower	461	880	10.0	4,590	8,763	0.00
Area 12	Middle	495	922	8.8	4,372	8,150	0.00
Area 12	Upper	171	443	9.7	1,656	4,301	0.00
Area 13	Lower	482	530	13.3	6,395	7,030	0.38
Area 13	Middle	230	273	14.3	3,290	3,900	0.30
Area 13	Upper	476	484	15.5	7,381	7,509	0.19
Area 14	Lower	238	341	7.4	1,769	2,529	2.08
Area 14	Middle	210	355	10.7	2,245	3,800	1.60
Area 14	Upper	483	688	9.2	4,449	6,334	1.63
Area 15	Lower	90	336	11.6	1,051	3,912	0.17
Area 15	Middle	115	336	8.5	974	2,838	0.62
Area 15	Upper	253	328	9.8	2,495	3,228	0.28
Area 17	Lower	509	928	12.1	6,177	11,267	0.84
Area 17	Middle	240	470	11.1	2,661	5,207	0.94
Area 17	Upper	450	878	11.4	5,116	9,977	0.90
Area 18	Lower	449	1894	6.4	2,864	12,087	0.00
Area 18	Middle	483	1892	4.7	2,282	8,940	0.00
Area 18	Upper	1132	1845	4.9	5,565	9,071	0.00
Area 19	Lower	224	331	8.0	1,788	2,647	2.32
Area 19	Middle	225	336	8.9	2,003	2,986	2.06
Area 19	Upper	228	337	8.4	1,920	2,834	1.98
Area 20	Lower	237	239	10.2	2,420	2,432	1.73
Area 20	Middle	244	246	9.3	2,272	2,289	1.68
Area 20	Upper	238	242	9.3	2,226	2,260	1.77
Area 21	Lower	0	0	11.2	0	0	1.76
Area 21	Middle	0	0	12.8	0	0	1.63
Area 21	Upper	0	0	12.0	0	0	1.58
Area 24	Lower	505	752	10.0	5,034	7,487	1.57
Area 24	Middle	495	769	9.1	4,506	7,003	1.69
Area 24	Upper	906	1443	9.4	8,516	13,563	1.63
Area 26	Lower	190	203	9.4	1,793	1,912	0.18
Area 26	Middle	201	201	9.5	1,909	1,910	0.35
Area 26	Upper	189	204	9.8	1,857	2,009	0.32
Area 27	Lower	211	821	13.8	2,903	11,317	1.36
Area 27	Middle	360	1651	13.0	4,667	21,389	1.39
Area 27	Upper	245	823	12.9	3,144	10,583	1.42
Area 28	Lower	579	2137	6.8	3,956	14,594	0.00
Area 28	Middle	741	2136	4.2	3,106	8,956	1.21
Area 28	Upper	902	2076	4.4	3,969	9,133	0.80

The methodology and assumptions used in arriving at the preceding estimates are provided within the body of this report. Note that all of Farrell Creek (W) and 30 percent of Graham were sterilized due to surface constraints that would likely prevent commercial recovery of resource.

GEOLOGICAL ASSESSMENT

The Triassic aged Montney Formation within British Columbia is bound unconformably below by the Belloy Formation and conformably above by the phosphatic shales of the Doig Formation. A generalized stratigraphic chart for the Montney Region in British Columbia is presented below.

Figure 3: Montney Region Stratigraphic Chart



The Montney is interpreted to consist of sediments deposited in a shallow marine shelf environment in which sediments flowed into the basin in a southwesterly direction as a series of channel and fan deposits. The entire Montney section averages approximately 300 metres with a net to gross of 30 to 80 percent. The reservoir units are largely comprised of very fine-grained sand and dolomitic siltstone with minor solid hydrocarbons (pyrobitumen) present.

In general, the Montney is comprised of multiple stratigraphic units, each having identifiable regional markers. Reservoir thickness and quality can vary significantly between units, and not all zones are capable of commercial development due to minimal hydrocarbon density. For the purposes of this study, stratigraphic groupings were divided into Upper, Middle, and Lower Montney packages. The Montney Reservoir is interpreted as basin centered gas; therefore, low water saturations are expected. Certain areas have been noted to have higher water saturations and may not be commercially viable.

As part of the geological assessment, McDaniel reviewed each area and stratigraphic zone from an exploitation perspective, with consideration given to current industry development trends. Development benches were limited to 60 metres per horizontal well, with certain development benches being developed with two to three layers of wells in the same stratigraphic interval.

ENGINEERING ASSESSMENT

Montney Data Set

Decline analysis was performed for approximately 3,000 horizontal producing wells in in the BC Montney. To the extent that data was available, recent 2018 vintage wells with at least three months of production data were reviewed as part of this assessment.

Standardized Estimated Ultimate Recoveries

Due to the significant variance in completed well lengths both between areas and within a given area, reservoir performance and type curves were assessed on a standardized 100 metre basis. The standardized well length provided a more accurate measure of performance and allowed for a better assessment of variations between vintages due to well length versus those associated with completion type and frac tonnage. Based on this analysis, it was observed that length standardized performance was relatively consistent between vintages, and in a number of areas has actually improved over time despite the increase in completed wellbore length. It is reasonable to assume that the lack of performance degradation at longer well lengths can be at least in part attributed to the advancements in completion techniques over time (slickwater, frac interval spacing) and due to the larger frac tonnage per metre of completed length observed in recent years.

Initial production rates and EURs for wells drilled in 2014 onwards on a standardized length basis are materially higher than previous vintages for the majority of the areas. It is our opinion that the improved performance provides reasonable assurance that the standardized 100 metre results can reasonably be scaled linearly with length.

For this assessment, standardized results have been scaled to 3,000 metres in all areas to reasonably maximize economic outcomes, while acknowledging drilling constraints that may prevent operators from drilling even longer horizontal wells. It should be noted by the reader that operators in the Montney have successfully demonstrated well lengths in excess of 4,000 metres.

CGR Ratios

Using McDaniel's proprietary EVA visual analytics software (version 18.6.0), we have compiled all publicly available wellhead condensate gas ratio (CGR) data and estimated ratios by area. Due to the general absence and inconsistency of CGR data within the public domain, as well as significant variance across geographical areas, area averages are considerably less reliable and accurate than the gas forecast. Based on publicly available data, areas within the Montney were characterized under the following general thermal maturity bands i.e. CGR expectations. It should be noted that data sets that were characterized as Dry Gas and Wet Gas, may deviate from the estimates outlined below.

Table 2: Thermal Maturity Bands

Acronym	Name	Approximate Stock Tank Yield (Test,IP1)		Approximate Stock Tank Yield	Approximate Stock Tank Yield	Approximate Stock Tank Yield (Life)
		Lower Limit	Upper Limit			
		Instantaneous	Instantaneous	Month 1 Avg	Month 12 Avg	EUR
		bbl/mmcf	bbl/mmcf	bbl/mmcf	bbl/mmcf	bbl/mmcf
14-DG	Dry Gas	-	-	-	-	-
13-WG	Wet Gas	-	25	25	19	19.4
12-GC	Gas Condensate	25	50	48	33	34.5
11-RGC1	Rich Gas Condensate 1	50	75	72	40	41.2
10-RGC2	Rich Gas Condensate 2	75	125	118	50	57.1
09-VRGC1	Very Rich Gas Condensate 1	125	175	164	65	75.3
08-VRGC2	Very Rich Gas Condensate 2	175	225	188	75	86.7
07-VRGC3	Very Rich Gas Condensate 3	225	275	258	100	116.3
06-VO1	Volatile Oil 1	275	500	473	185	211.0
05-VO2	Volatile Oil 2	500	750	708	275	313.0
04-VO3	Volatile Oil 3	750	1,000	950	371	422.0
03-BO	Black Oil	1,000	-			
02-MED	Medium					
01-Heavy	Heavy					
00-BIT	Bitumen					

Outlined below are the estimated CGRs by area. The CGR estimates below are intended to represent area averages and may deviate from recent vintages given that operators have largely focused recent development on the most liquids rich portions of each area.

Table 3a: Public Data CGRs by Area - Heritage

Area	Zone	CGR Classification	Lifetime CGR (bbl/mmcf)
Area 1	Lower	14-DG	2
Area 1	Middle	14-DG	2
Area 1	Upper	14-DG	2
Area 2	Lower	13-WG	19
Area 2	Middle	13-WG	19
Area 2	Upper	13-WG	19
Area 4	Lower	14-DG	0
Area 4	Middle	14-DG	0
Area 4	Upper	14-DG	0
Area 7	Lower	14-DG	10
Area 7	Middle	14-DG	10
Area 7	Upper	14-DG	10
Area 9	Lower	14-DG	0
Area 9	Middle	14-DG	0
Area 9	Upper	14-DG	0
Area 10	Lower	13-WG	19
Area 10	Middle	13-WG	19
Area 10	Upper	13-WG	19
Area 11	Lower	12-GC	35
Area 11	Middle	12-GC	35
Area 11	Upper	12-GC	35
Area 16	Lower	14-DG	0
Area 16	Middle	14-DG	0
Area 16	Upper	14-DG	0
Area 22	Lower	14-DG	2
Area 22	Middle	14-DG	2
Area 22	Upper	14-DG	2
Area 23	Lower	14-DG	3
Area 23	Middle	14-DG	3
Area 23	Upper	14-DG	3
Area 25	Lower	14-DG	0
Area 25	Middle	14-DG	0
Area 25	Upper	14-DG	0
Area 29	Lower	07-VRGC3	130
Area 29	Middle	07-VRGC3	130
Area 29	Upper	07-VRGC3	130
Area 30	Lower	14-DG	0
Area 30	Middle	14-DG	0
Area 30	Upper	14-DG	0

Table 3b: Public Data CGRs by Area - Northern

Area	Zone	CGR Classification	Lifetime CGR (bbl/mmcf)
Area 3	Lower	14-DG	0
Area 3	Middle	14-DG	0
Area 3	Upper	14-DG	0
Area 5	Lower	13-WG	19
Area 5	Middle	13-WG	19
Area 5	Upper	13-WG	19
Area 6	Lower	13-WG	19
Area 6	Middle	13-WG	19
Area 6	Upper	13-WG	19
Area 8	Lower	13-WG	15
Area 8	Middle	13-WG	15
Area 8	Upper	13-WG	15
Area 12	Lower	13-WG	25
Area 12	Middle	13-WG	25
Area 12	Upper	13-WG	25
Area 13	Lower	13-WG	15
Area 13	Middle	13-WG	15
Area 13	Upper	13-WG	15
Area 14	Lower	14-DG	1
Area 14	Middle	14-DG	1
Area 14	Upper	14-DG	1
Area 15	Lower	13-WG	19
Area 15	Middle	13-WG	19
Area 15	Upper	13-WG	19
Area 17	Lower	14-DG	10
Area 17	Middle	14-DG	10
Area 17	Upper	14-DG	10
Area 18	Lower	08-VRGC2	87
Area 18	Middle	08-VRGC2	87
Area 18	Upper	08-VRGC2	87
Area 19	Lower	14-DG	0
Area 19	Middle	14-DG	0
Area 19	Upper	14-DG	0
Area 20	Lower	14-DG	0
Area 20	Middle	14-DG	0
Area 20	Upper	14-DG	0
Area 21	Lower	14-DG	1
Area 21	Middle	14-DG	1
Area 21	Upper	14-DG	1
Area 24	Lower	14-DG	2
Area 24	Middle	14-DG	2
Area 24	Upper	14-DG	2
Area 26	Lower	13-WG	19
Area 26	Middle	13-WG	19
Area 26	Upper	13-WG	19
Area 27	Lower	14-DG	0
Area 27	Middle	14-DG	0
Area 27	Upper	14-DG	0
Area 28	Lower	12-GC	35
Area 28	Middle	12-GC	35
Area 28	Upper	12-GC	35

High Density Montney Study

As part of the regional analysis, McDaniel reviewed all high-density pads within both the British Columbia and Alberta Montney to substantiate reasonable recovery factor ranges at various thermal maturity bands. Only pads that consisted of at least three lateral wells and two development layers were considered high density. By imposing minimum development density requirements, boundary effects were reduced, leading to higher confidence estimates. Furthermore, only pads that have reasonable production history and well-defined declines were included in the assessment. In total, approximately 100 pads were assessed as part of this evaluation. The following table outlines the high-density recovery factor maximums that resulted from the analysis.

Table 4: Maximum Recovery Factor by Thermal Maturity Band

Thermal Maturity Band	Approximate CGR (bbl/mmcf, lifetime)	Maximum Gas Recovery Factor (%)
Dry Gas	0-10	70
Wet Gas	10-27	65
Gas Condensate	27-37	60
Rich Gas Condensate	37-65	50
Very Rich Gas Condensate	65-150	40
Volatile Oil	>150	25

The recovery factors noted in the table above are maximums and represent high-density pad development with vertical development spacing of approximately 40 to 60 metres. Within the area analysis, a maximum effective pay thickness of 50 to 60 metres was incorporated, resulting in lower recovery factors for thicker single layer developments

Machine Learning Analysis

To support type curve development, a multivariate machine learning analysis was carried out on existing BC Montney wells. The primary purpose of the analysis was to improve our ability to estimate production outcomes across changing geological characteristics and well designs based on observed data. The biggest drivers of performance according to the machine learning analysis were reviewed and ensured to be reasonable based on geological and engineering principles, visual analytics and our Montney experience.

This analysis also provided a useful basis, along with the geological and engineering work, from which to estimate economically optimal well designs in each area. Machine learning based productivity estimates were generated for a variety of well designs across all areas and development layers, and these estimates were used in conjunction with engineering, geological and volumetric recovery factor perspectives to arrive at our best estimate type curves.

TYPE CURVE ECONOMICS AND OPTIMIZATION

Area type curves were generated on an area and stratigraphic basis i.e. Upper, Middle or Lower Montney. Type curves were based on a combination of volumetric analysis, Machine Learning analysis and economic optimization. Economic optimization was predicated on the McDaniel January 1, 2019 price forecast which includes a long-term AECO price of $3.00/MMBtu (2019$) and long-term WTI of $67.50/bbl (2019$). A copy of the January 1, 2019 pricing is provided in the attached appendices. It should be noted that the type curves generated are non-unique and that different supply outcomes and curves would be produced under different pricing assumptions. A minimum 10 percent half-cycle rate of return on all wells was applied to be included in the assessment as economic. A half-cycle rate of return of 10 percent does not necessarily imply commercial viability as other economic inputs such as General and Administrative Expenses, Taxes and Producer Cost of Capital would need to be considered.

Capital Cost Model

A capital cost model for drilling, completion, wellsite equip and tie-in costs was created to estimate the cost for each well design in each layer for each area. The cost model is a function of vertical depth, lateral length, proppant intensity and stage spacing and is based on observed historical and forward expected capital costs within the Montney. All capital costs are estimated under the assumption that wells will be drilled in pad configurations. A summary of the cost model is presented in the attached appendices.

Operating Cost Model

Operating cost models were generated for the Montney with consideration given to liquids content, NGL yields and condensate/oil production. The generated models are based on observed historical and forward looking expectations for operating costs in the Montney. A summary of the operating cost parameters and product yield parameters is presented below.

Table 5: Operating Cost Parameters and Product Yield Parameters

Input	Unit	DG	WG/GC	RGC1+
Gas Shrinkage	%	3	7	15
C2 Ratio	bbl/mmcf	0	0	0
C3 Ratio	bbl/mmcf	3	15	25
C4 Ratio	bbl/mmcf	3	15	25
C5+ Ratio	bbl/mmcf	3	8	10
Heating Value	Btu/cf	1,075	1,100	1,175
Variable Gas	$/mcf	0.35	1.25	2.50
Variable Condensate/Oil	$/bbl	3.50	3.50	3.50
Fixed Cost	$/WM	3,000	9,000	12,000
Approximate Total OPEX	$/BOE	3.00	6.00	9.00

FINAL TYPE CURVES, INVENTORY AND COMPLETION PARAMETERS

Based on the aforementioned cost information in combination with the geological and engineering analysis, the following optimized type-curves were generated for each of the defined areas.

Table 6a: Type Curve Parameters – Heritage

Area	Layer (U/M/L)	Proppant Intensity (t/m)	Stage Spacing (m)	Well Spacing (m)	Gas EUR per 100 m (Best Estimate) (MMcf per 100 m)	Condensate/Oil EUR per 100 m (Best Estimate) (Mbbl per 100 m)	Lateral Length (m)	Gas EUR (Best Estimate) (MMcf)	Condensate/Oil EUR (Best Estimate) (Mbbl)	CapEx ($, millions)	NPV10 ($, millions)
Area 1	Lower	1	150	400	377	0.8	3,000	11,306	23	7.92	6.62
Area 1	Middle	1	50	400	444	0.9	3,000	13,324	27	8.59	9.06
Area 1	Upper	1.5	50	400	470	0.9	3,000	14,107	28	9.67	9.26
Area 2	Lower	1	50	400	136	2.7	3,000	4,082	80	8.06	1.95
Area 2	Middle	1	50	400	266	5.1	3,000	7,991	153	8.13	7.17
Area 2	Upper	1	50	400	330	6.3	3,000	9,908	189	8.20	9.67
Area 4	Lower	1	50	400	403	0.0	3,000	12,087	0	8.22	6.89
Area 4	Middle	1	50	400	298	0.0	3,000	8,929	0	8.28	3.57
Area 4	Upper	1	50	400	459	0.0	3,000	13,775	0	8.38	8.90
Area 7	Lower	1.5	50	400	323	3.2	3,000	9,678	97	8.98	7.20
Area 7	Middle	1	100	400	211	2.1	3,000	6,328	63	7.69	3.76
Area 7	Upper	1.5	50	400	336	3.4	3,000	10,086	101	9.09	7.05
Area 9	Lower	1.5	50	400	416	0.0	3,000	12,466	0	9.84	6.35
Area 9	Middle	1	150	400	252	0.0	3,000	7,562	0	8.37	1.97
Area 9	Upper	1.5	50	400	485	0.0	3,000	14,548	0	9.99	8.88
Area 10	Lower	1	50	400	210	4.0	3,000	6,314	121	8.04	4.29
Area 10	Middle	1	50	400	262	5.1	3,000	7,850	153	8.11	8.42
Area 10	Upper	1	50	400	280	5.4	3,000	8,414	163	8.22	9.07
Area 11	Lower	1.5	50	300	295	9.8	3,000	8,842	294	9.25	10.90
Area 11	Middle	1.5	50	300	247	8.3	3,000	7,408	248	9.36	8.50
Area 11	Upper	1.5	50	300	325	10.8	3,000	9,743	324	9.44	12.46
Area 16	Lower	1.5	50	400	513	0.0	3,000	15,380	0	9.75	8.34
Area 16	Middle	1	50	400	432	0.0	3,000	12,952	0	8.60	6.88
Area 16	Upper	1.5	50	400	485	0.0	3,000	14,538	0	9.70	8.32
Area 22	Lower	1.5	50	400	490	1.0	3,000	14,696	29	9.70	10.04
Area 22	Middle	1.5	50	400	326	0.7	3,000	9,766	20	9.77	4.66
Area 22	Upper	1.5	50	400	583	1.2	3,000	17,505	35	9.85	11.74
Area 23	Lower	1.5	50	400	610	1.8	3,000	18,294	55	9.45	13.56
Area 23	Middle	1.5	50	400	321	1.0	3,000	9,629	29	9.55	4.35
Area 23	Upper	1.5	50	400	632	1.9	3,000	18,963	57	9.63	14.84
Area 25	Lower	2	50	400	314	0.0	3,000	9,423	0	11.01	2.56
Area 25	Middle	1.5	50	400	265	0.0	3,000	7,943	0	10.05	2.02
Area 25	Upper	2	50	400	372	0.0	3,000	11,148	0	10.97	4.21
Area 29	Lower	2.5	50	300	100	13.0	3,000	2,997	389	10.63	5.90
Area 29	Middle	2.5	50	300	99	12.7	3,000	2,979	381	10.71	4.93
Area 29	Upper	2.5	50	300	100	12.9	3,000	2,996	388	10.81	5.61
Area 30	Lower	1	50	400	180	0.0	3,000	5,406	0	9.79	Sub-economic
Area 30	Middle	1	50	400	173	0.0	3,000	5,197	0	9.74	Sub-economic
Area 30	Upper	1	50	400	156	0.0	3,000	4,674	0	9.67	Sub-economic

Table 6b: Type Curve Parameters – Northern

Area	Layer (U/M/L)	Proppant Intensity (t/m)	Stage Spacing (m)	Well Spacing (m)	Gas EUR per 100 m (Best Estimate) (MMcf per 100 m)	Condensate/Oil EUR per 100 m (Best Estimate) (Mbbl per 100 m)	Lateral Length (m)	Gas EUR (Best Estimate) (MMcf)	Condensate/Oil EUR (Best Estimate) (Mbbl)	CapEx ($, millions)	NPV10 ($, millions)
Area 3	Lower	1	50	400	268	0.0	3,000	8,055	0	8.13	3.91
Area 3	Middle	1	100	400	233	0.0	3,000	6,982	0	7.71	2.64
Area 3	Upper	1	50	400	261	0.0	3,000	7,841	0	7.86	2.74
Area 5	Lower	1.5	50	400	385	7.4	3,000	11,543	223	9.02	13.37
Area 5	Middle	1.5	50	400	358	6.9	3,000	10,732	206	8.93	11.12
Area 5	Upper	1.5	50	400	378	7.3	3,000	11,338	218	8.88	12.60
Area 6	Lower	2	50	400	435	8.4	3,000	13,060	251	10.01	15.34
Area 6	Middle	2	50	400	342	6.7	3,000	10,272	200	9.91	12.06
Area 6	Upper	2	50	400	373	7.2	3,000	11,197	216	9.87	12.08
Area 8	Lower	1	50	400	235	3.5	3,000	7,063	106	7.97	4.92
Area 8	Middle	1	50	400	280	4.2	3,000	8,411	126	7.87	6.85
Area 8	Upper	1	50	400	265	4.0	3,000	7,964	119	7.83	6.16
Area 12	Lower	1.5	50	400	332	8.3	3,000	9,958	250	9.22	12.82
Area 12	Middle	1.5	50	400	295	7.4	3,000	8,837	223	9.07	11.11
Area 12	Upper	1.5	50	400	324	8.2	3,000	9,711	245	9.00	11.96
Area 13	Lower	2	50	400	442	6.6	3,000	13,259	199	10.51	12.98
Area 13	Middle	2	50	400	476	7.1	3,000	14,293	214	10.46	14.19
Area 13	Upper	2	50	400	517	7.8	3,000	15,515	233	10.37	16.22
Area 14	Lower	1	50	400	247	0.2	3,000	7,421	7	8.22	3.31
Area 14	Middle	1	50	400	357	0.4	3,000	10,701	11	8.19	6.11
Area 14	Upper	1	50	400	307	0.3	3,000	9,209	9	8.06	5.78
Area 15	Lower	1.5	50	400	388	7.4	3,000	11,647	223	9.01	12.31
Area 15	Middle	1.5	50	400	282	5.4	3,000	8,457	162	8.92	7.59
Area 15	Upper	1.5	50	400	328	6.3	3,000	9,843	190	8.87	10.49
Area 17	Lower	1.5	50	400	405	4.0	3,000	12,138	121	9.57	10.40
Area 17	Middle	1.5	50	400	369	3.7	3,000	11,079	111	9.52	9.25
Area 17	Upper	1.5	50	400	379	3.8	3,000	11,359	114	9.45	9.57
Area 18	Lower	3	50	300	213	18.7	3,000	6,381	560	11.36	14.66
Area 18	Middle	3	50	300	157	13.7	3,000	4,724	410	11.26	8.25
Area 18	Upper	3	50	300	164	14.4	3,000	4,915	431	11.20	9.42
Area 19	Lower	1.5	50	400	266	0.0	3,000	7,988	0	8.97	2.46
Area 19	Middle	1.5	50	400	297	0.0	3,000	8,898	0	8.90	3.46
Area 19	Upper	1	100	400	280	0.0	3,000	8,406	0	7.48	3.47
Area 20	Lower	1	50	400	340	0.0	3,000	10,197	0	8.06	5.44
Area 20	Middle	1	50	400	310	0.0	3,000	9,308	0	7.97	5.12
Area 20	Upper	1	50	400	312	0.0	3,000	9,348	0	7.93	4.61
Area 21	Lower	2	50	400	375	0.4	3,000	11,249	11	10.51	5.78
Area 21	Middle	2	50	400	427	0.4	3,000	12,822	13	10.45	6.89
Area 21	Upper	1.5	50	400	400	0.4	3,000	11,986	12	9.51	6.91
Area 24	Lower	1	50	400	332	0.7	3,000	9,962	20	8.41	6.12
Area 24	Middle	1	50	400	303	0.6	3,000	9,101	18	8.31	5.25
Area 24	Upper	1	50	400	313	0.6	3,000	9,397	19	8.23	5.58
Area 26	Lower	1.5	50	400	314	6.1	3,000	9,417	183	9.16	10.90
Area 26	Middle	1.5	50	400	317	6.1	3,000	9,510	184	9.03	9.91
Area 26	Upper	1.5	50	400	328	6.3	3,000	9,844	190	8.99	10.17
Area 27	Lower	1	50	400	460	0.0	3,000	13,787	0	8.51	9.07
Area 27	Middle	1	50	400	432	0.0	3,000	12,954	0	8.38	8.58
Area 27	Upper	1.5	50	400	429	0.0	3,000	12,858	0	9.29	8.71
Area 28	Lower	1.5	50	300	228	7.7	3,000	6,829	232	8.75	8.97
Area 28	Middle	1.5	50	300	140	4.7	3,000	4,194	142	8.66	2.90
Area 28	Upper	1.5	50	300	147	5.0	3,000	4,400	151	8.62	3.96

Break-Even Supply Costs

McDaniel completed a break-even analysis of the generated type curves by varying the AECO gas price while holding all other price and cost variables constant at 2019 levels from the McDaniel January 1, 2019 price forecast (WTI at $56.50/bbl). Below is a summary of the break-even supply costs by area and stratigraphic interval.

Table 7a: Break-even Supply Costs – Heritage

Area	Development Layer (U/M/L)	AECO Supply Cost ($/MMBtu)
Area 1	Lower	1.40
Area 1	Middle	1.22
Area 1	Upper	1.28
Area 2	Lower	1.80
Area 2	Middle	0.58
Area 2	Upper	0.29
Area 4	Lower	1.47
Area 4	Middle	1.99
Area 4	Upper	1.30
Area 7	Lower	1.08
Area 7	Middle	1.52
Area 7	Upper	1.15
Area 9	Lower	1.63
Area 9	Middle	2.46
Area 9	Upper	1.40
Area 10	Lower	1.11
Area 10	Middle	0.38
Area 10	Upper	0.32
Area 11	Lower	0.00
Area 11	Middle	0.00
Area 11	Upper	0.00
Area 16	Lower	1.46
Area 16	Middle	1.51
Area 16	Upper	1.44
Area 22	Lower	1.22
Area 22	Middle	1.78
Area 22	Upper	1.15
Area 23	Lower	0.98
Area 23	Middle	1.81
Area 23	Upper	0.93
Area 25	Lower	2.42
Area 25	Middle	2.49
Area 25	Upper	2.06
Area 29	Lower	0.00
Area 29	Middle	0.00
Area 29	Upper	0.00
Area 30	Lower	4.40
Area 30	Middle	4.50
Area 30	Upper	4.68

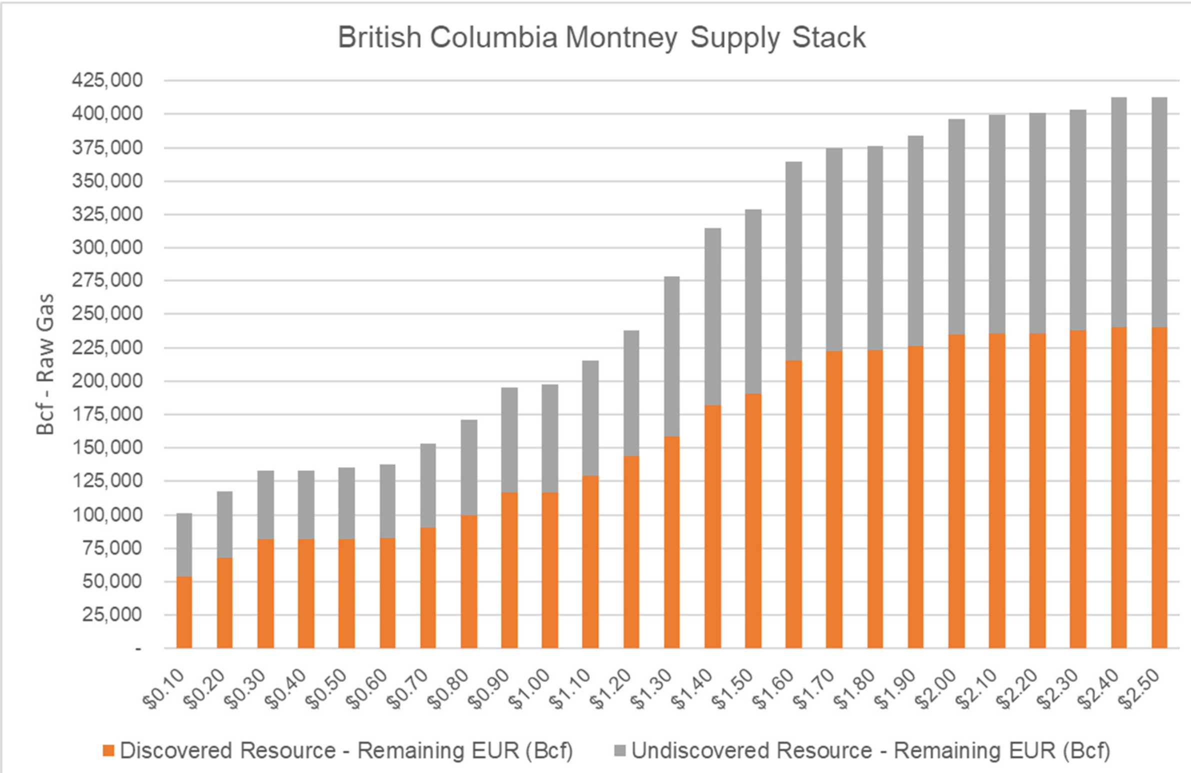
Table 7b: Break-even Supply Costs – Northern

Area	Development Layer (U/M/L)	AECO Supply Cost ($/MMBtu)
Area 3	Lower	1.98
Area 3	Middle	2.26
Area 3	Upper	2.19
Area 5	Lower	0.09
Area 5	Middle	0.24
Area 5	Upper	0.13
Area 6	Lower	0.00
Area 6	Middle	0.16
Area 6	Upper	0.25
Area 8	Lower	1.11
Area 8	Middle	0.78
Area 8	Upper	0.88
Area 12	Lower	0.00
Area 12	Middle	0.00
Area 12	Upper	0.00
Area 13	Lower	0.38
Area 13	Middle	0.30
Area 13	Upper	0.19
Area 14	Lower	2.08
Area 14	Middle	1.60
Area 14	Upper	1.63
Area 15	Lower	0.17
Area 15	Middle	0.62
Area 15	Upper	0.28
Area 17	Lower	0.84
Area 17	Middle	0.94
Area 17	Upper	0.90
Area 18	Lower	0.00
Area 18	Middle	0.00
Area 18	Upper	0.00
Area 19	Lower	2.32
Area 19	Middle	2.06
Area 19	Upper	1.98
Area 20	Lower	1.73
Area 20	Middle	1.68
Area 20	Upper	1.77
Area 21	Lower	1.76
Area 21	Middle	1.63
Area 21	Upper	1.58
Area 24	Lower	1.57
Area 24	Middle	1.69
Area 24	Upper	1.63
Area 26	Lower	0.18
Area 26	Middle	0.35
Area 26	Upper	0.32
Area 27	Lower	1.36
Area 27	Middle	1.39
Area 27	Upper	1.42
Area 28	Lower	0.00
Area 28	Middle	1.21
Area 28	Upper	0.80

Supply Curve

Based on the break-even supply costs, the supply stack below was created to show discovered and undiscovered resources remaining at varied levels of AECO pricing.

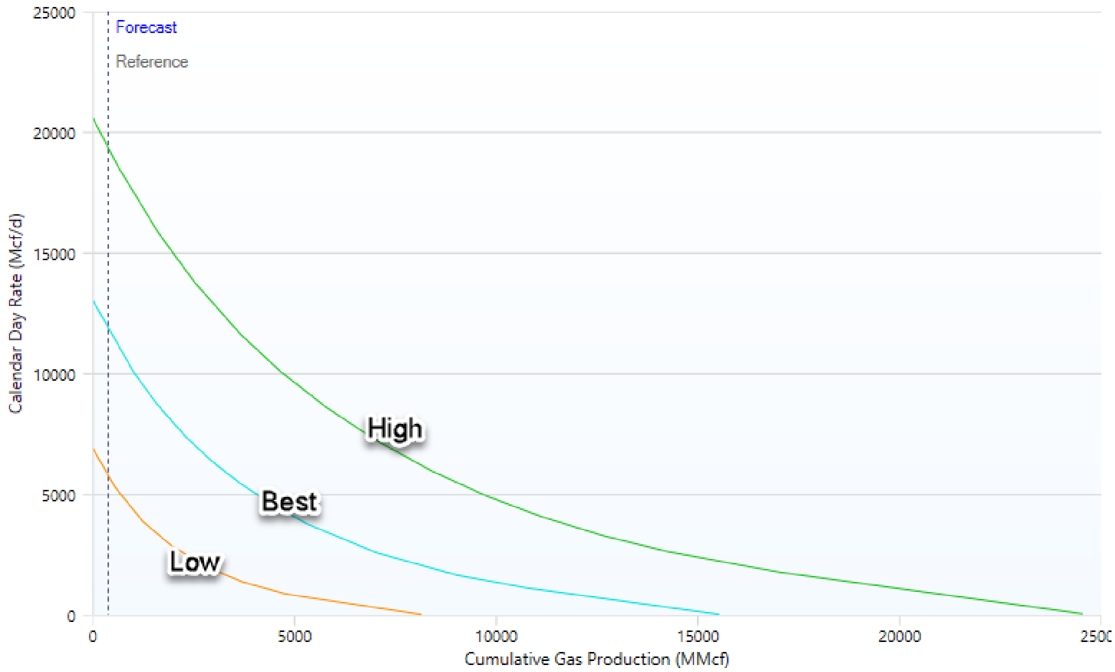
Figure 4: BC Montney Supply Stack



Low and High Estimate Type Curves

Low and High Estimate area type curves were generated using a probabilistic analysis of area specific EURs. The Low and High Estimate EURs correlate to P_{90} and P_{10} confidence levels for a single well outcome and therefore represent a relatively wide variance or uncertainty. Notably, when drilling a significant number of future wells, aggregation principles must be considered and the resulting P_{90} and P_{10} variance of the combined drilling program will be significantly smaller. As such, the estimates presented should not be used when assessing a significant well inventory as the aggregated outcome would be materially too conservative or optimistic. The Low and High Estimate type curves for the Area 13 Upper area are presented below with the Best Estimate type curve for reference. The remaining low and high type curves are presented in the ValNav database upload.

Figure 5: Area 13 Upper – Low, Best, and High Estimate Type Curves



In preparing this report, we relied upon technical well data and other relevant data from public sources as well as non-public data supplied by the Company. The extent and character of all information used in this assessment has been accepted as represented without independent verification.

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Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.
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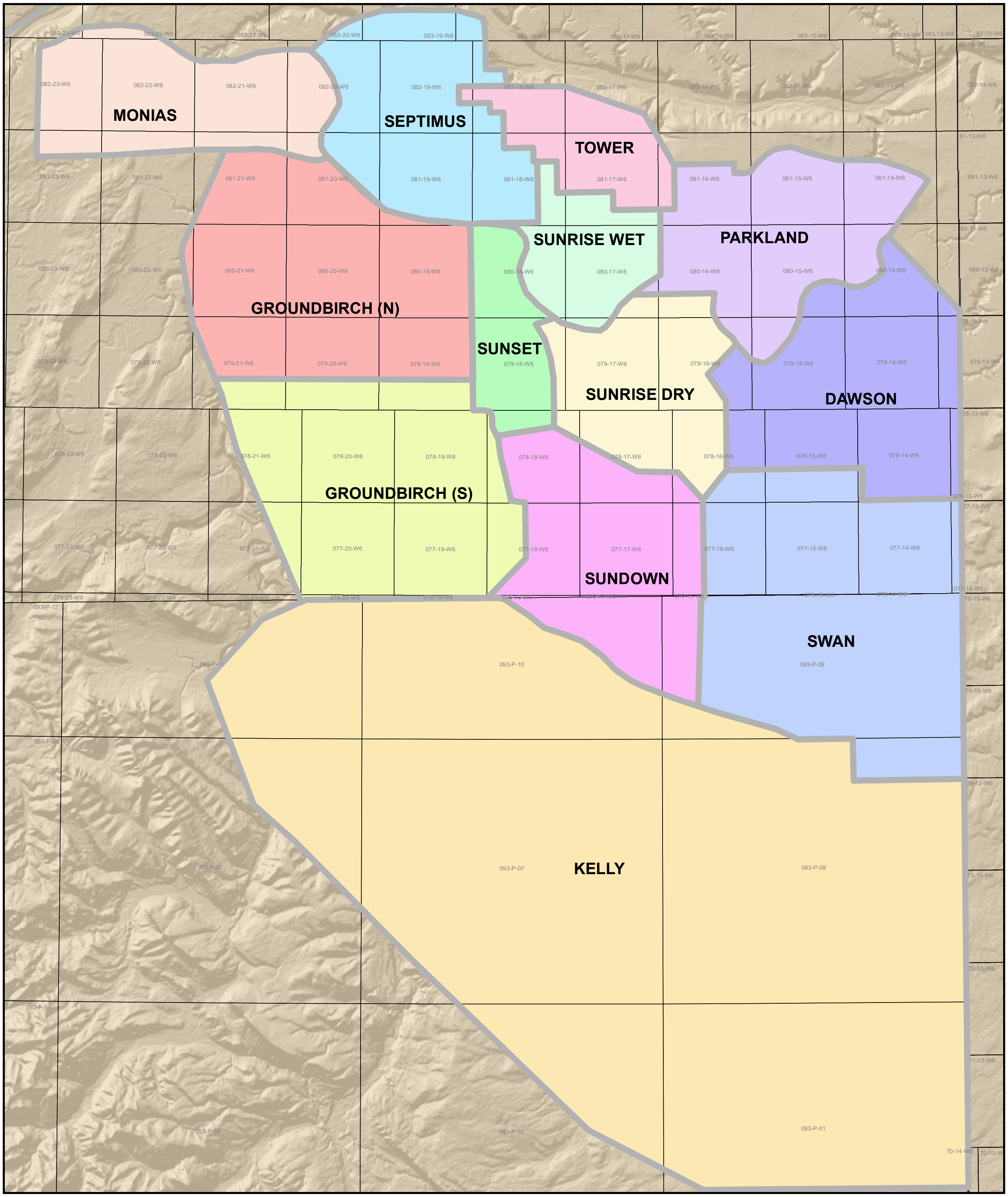

Legend

DAWSON
GROUNDBIRCH (N)
GROUNDBIRCH (S)
KELLY
MONIAS
PARKLAND
SEPTIMUS
SUNDOWN
SUNRISE DRY
SUNRISE WET
SUNSET
SWAN
TOWER

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Kilometres

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Miles

Government of British Columbia

HERITAGE MONTNEY
SUBDIVISIONS

Software: ESRI, ArcMap 10.4.1

Montney_Regional_Areas_Heritage_Montney_Subdivisions

Map Created by: wpf-rcf 04/30/2019	Map Edited by: rcf 04/30/2019	Map Finalized: 04/30/2019

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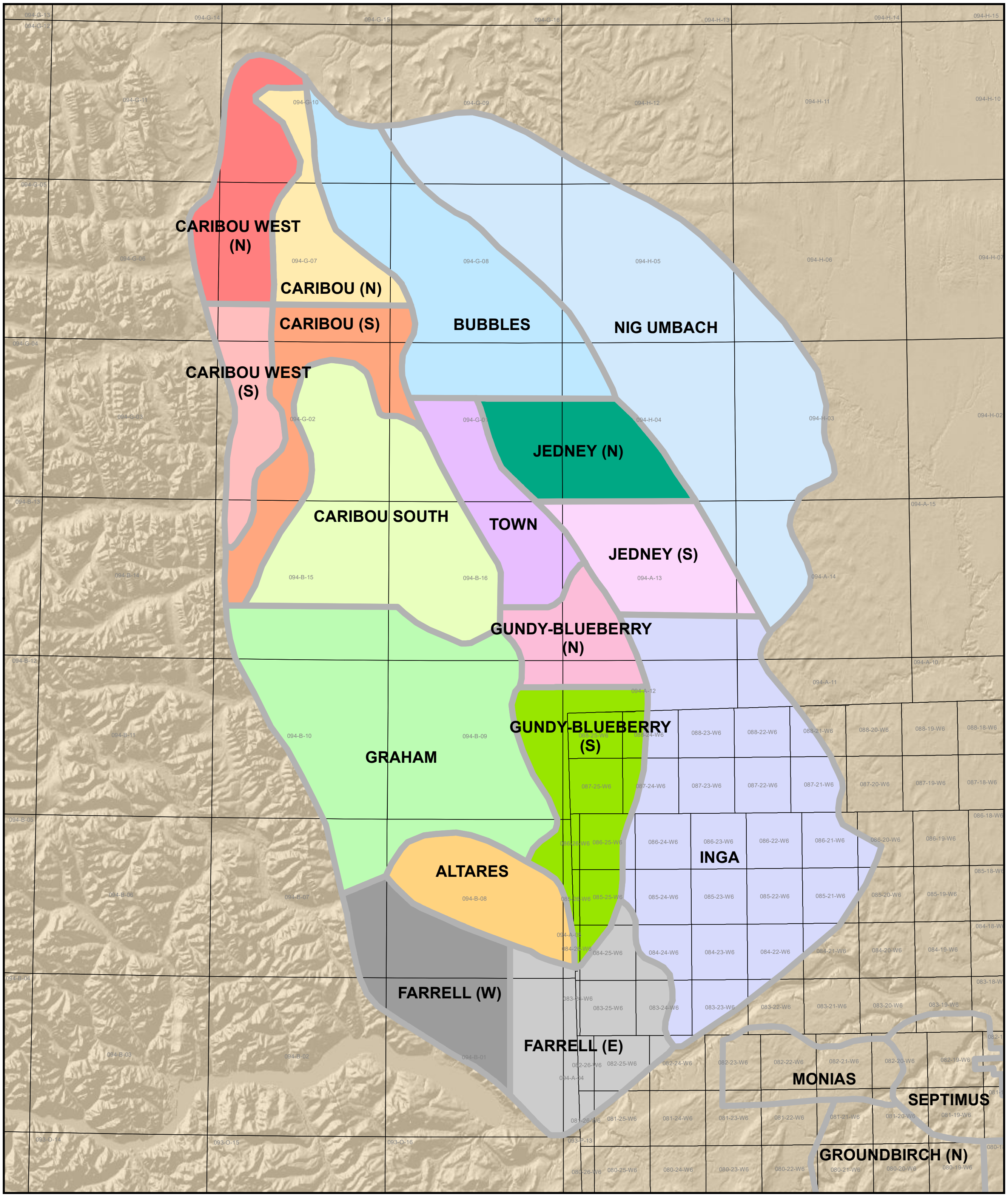

Legend

ALTARES	FARRELL (W)
BUBBLES	GRAHAM
CARIBOU (N)	GUNDY-BLUEBERRY (N)
CARIBOU (S)	GUNDY-BLUEBERRY (S)
CARIBOU SOUTH	INGA
CARIBOU WEST (N)	JEDNEY (N)
CARIBOU WEST (S)	JEDNEY (S)
FARRELL (E)	NIG UMBACH
	TOWN

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Miles

Government of British Columbia

NORTHERN MONTNEY SUBDIVISIONS

Software: ESRI, ArcMap 10.4.1

Montney_Regional_Areas_Northern_Montney_Subdivisions

Map Created by: wpf-rcf	Map Edited by: rcf	Map Finalized:
04/30/2019	04/30/2019	04/30/2019

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McDaniel & Associates Consultants Ltd.

Table 1

Summary of Crude Oil and Natural Gas Liquids Price Forecasts
January 1, 2019

Year	WTI Crude Oil $US/bbl (1)	Brent Crude Oil $US/bbl (2)	Edmonton Light Crude Oil $C/bbl (3)	Alberta Bow River Hardisty Crude Oil $C/bbl (4)	Western Canadian Select Crude Oil $C/bbl (5)	Alberta Heavy Crude Oil $C/bbl (6)	Sask Cromer Medium Crude Oil $C/bbl (7)	Edmonton Cond. & Natural Gasolines $/bbl	Edmonton Ethane $/bbl	Edmonton Propane $/bbl	Edmonton Butanes $/bbl	Inflation %	US/CAN Exchange Rate $US/$CAN
History													
1987	19.30		24.30	20.79				23.80		9.98	16.80		0.755
1988	16.00		18.70	14.41				18.30		8.19	12.95		0.812
1989	19.60		22.20	18.09				21.80		8.14	10.35		0.844
1990	24.50		27.60	21.06		16.00		27.00		13.67	16.21		0.857
1991	21.40		23.40	15.07		9.05		22.90		11.91	15.25		0.873
1992	20.55		23.50	17.52		12.95		23.00		10.55	14.05		0.828
1993	18.60		21.90	16.70		13.30		21.50		14.10	13.55		0.775
1994	17.20		22.20	18.43		15.00		21.75		12.50	13.45		0.732
1995	18.45		24.25	20.80		17.25		23.76		13.90	13.80		0.729
1996	22.10		29.35	25.11		20.05		28.75		22.20	17.15		0.733
1997	20.55	19.09	27.80	21.22		14.40		31.10		18.60	19.05		0.722
1998	14.40	12.77	20.35	14.60		9.40	17.00	21.85		10.95	11.90		0.687
1999	19.25	17.86	27.60	23.35		19.65	25.47	27.60		15.45	17.73		0.673
2000	30.31	28.40	44.72	34.35		27.80	40.10	46.25		31.55	35.00		0.674
2001	25.97	24.42	39.60	25.07		18.05	32.22	42.44		29.15	28.45		0.646
2002	26.10	24.95	39.95	31.65		27.60	34.93	40.79		19.85	26.10		0.637
2003	31.05	28.85	43.15	32.68		27.40	37.57	44.19		30.15	33.45		0.716
2004	41.40	38.30	52.54	37.60	36.14	30.40	45.94	54.09		33.28	39.45		0.770
2005	56.56	54.48	68.72	44.83	44.60	34.35	57.47	69.63		43.29	52.58		0.826
2006	66.23	65.20	72.80	51.55	51.22	43.14	61.25	75.06		44.05	60.10		0.880
2007	72.30	72.80	76.35	53.25	52.90	44.63	65.40	77.36	NA	49.45	63.75		0.935
2008	99.60	97.80	102.20	84.30	82.94	75.55	93.20	104.75	NA	58.40	75.25		0.943
2009	61.80	61.60	65.90	60.30	58.58	55.30	62.80	68.15	NA	38.60	49.25		0.880
2010	79.50	79.90	77.50	68.50	67.23	61.45	73.80	84.25	NA	46.70	66.05		0.971
2011	95.10	111.25	95.00	78.55	77.10	67.90	88.90	104.20	NA	55.15	76.50		1.012
2012	94.20	111.65	86.10	74.35	73.08	63.65	82.10	100.80	NA	28.60	69.55		1.000
2013	97.95	108.60	93.05	76.55	75.25	65.25	88.25	104.65	NA	38.90	69.40		0.971
2014	93.00	99.00	93.50	80.40	79.10	71.20	87.80	102.40	NA	45.05	69.60		0.906
2015	48.80	52.35	57.75	46.10	44.80	39.55	51.45	60.30	NA	6.65	35.55		0.780
2016	43.30	43.55	53.85	40.30	39.00	33.35	48.95	56.20	NA	13.15	34.35		0.760
2017	50.90	54.25	62.85	52.00	50.70	45.20	59.85	66.85	NA	28.90	44.60		0.770
2018	65.00	71.30	72.20	54.00	52.70	42.90	71.10	80.80	NA	27.55	32.80		0.770
Forecast													
2019	56.50	64.50	63.30	48.70	47.50	39.90	60.80	67.30	6.60	22.80	19.60	0.0	0.750
2020	63.80	67.90	74.30	58.70	58.00	50.20	70.20	78.40	8.00	26.90	35.40	2.0	0.775
2021	67.60	70.70	78.50	65.20	64.40	56.10	73.00	82.70	9.40	28.90	43.10	2.0	0.800
2022	71.60	73.70	83.40	69.20	68.40	59.60	77.60	87.60	11.40	33.00	51.90	2.0	0.800
2023	73.10	75.30	85.10	70.60	69.80	60.80	79.10	89.40	12.00	33.80	56.10	2.0	0.800
2024	74.50	76.70	86.80	72.00	71.20	62.10	80.70	91.20	12.40	34.60	57.20	2.0	0.800
2025	76.00	78.30	88.50	73.50	72.60	63.30	82.30	93.00	12.40	35.10	58.40	2.0	0.800
2026	77.50	79.80	90.30	74.90	74.00	64.60	84.00	94.90	12.60	35.80	59.50	2.0	0.800
2027	79.10	81.40	92.10	76.40	75.50	65.90	85.70	96.80	12.80	36.50	60.70	2.0	0.800
2028	80.70	83.10	94.00	78.00	77.10	67.20	87.40	98.80	13.20	37.30	62.00	2.0	0.800
2029	82.30	84.70	95.80	79.50	78.60	68.50	89.10	100.70	13.40	38.00	63.20	2.0	0.800
2030	83.90	86.40	97.70	81.10	80.10	69.90	90.90	102.70	13.80	38.80	64.40	2.0	0.800
2031	85.60	88.10	99.70	82.80	81.80	71.30	92.70	104.80	14.00	39.60	65.70	2.0	0.800
2032	87.30	89.90	101.70	84.40	83.40	72.70	94.60	106.90	14.20	40.30	67.10	2.0	0.800
2033	89.10	91.70	103.80	86.20	85.10	74.20	96.50	109.10	14.60	41.20	68.40	2.0	0.800
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.800

(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API/0.5% sulphur
(2) North Sea Brent Blend 37 degrees API/1.0% sulphur
(3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(4) Bow River at Hardisty, Alberta (Heavy stream)
(5) Western Canadian Select at Hardisty, Alberta
(6) Heavy crude oil 12 degrees API at Hardisty, Alberta (after deduction of blending costs to reach pipeline quality)
(7) Midale Cromer crude oil 29 degrees API, 2.0% sulphur

G190101 - Effective January 1, 2019

McDaniel & Associates Consultants Ltd.

Summary of Natural Gas Price Forecasts
January 1, 2019

Year	U.S. Henry Hub Gas Price $US/MMBtu	Alberta AECO Spot Price $C/MMBtu	Alberta Average Plantgate $C/MMBtu (1)	Alberta Aggregator Plantgate $C/MMBtu	Empress $C/MMBtu	Sask. Prov. Gas Plantgate $C/MMBtu	British Columbia Average Plantgate $C/MMBtu	British Columbia Station 2 $C/MMBtu
History								
1987	1.50		1.64	1.82				
1988	1.85		1.44	1.66				
1989	1.68		1.47	1.57				
1990	1.67		1.45	1.64				
1991	1.54		1.18	1.31			1.13	
1992	1.79		1.22	1.30			1.10	
1993	2.13		1.89	1.60			2.13	
1994	1.92		1.83	1.81			1.87	
1995	1.62		1.18	1.23			1.12	
1996	2.50	1.39	1.54	1.63			1.47	
1997	2.59	1.87	1.84	1.86			1.98	
1998	2.06	2.04	1.90	1.88		2.05	2.00	
1999	2.28	2.96	2.60	2.46		2.82	2.77	
2000	4.31	5.02	4.80	4.57		4.78	4.88	
2001	3.98	6.30	5.90	5.25		5.71	6.30	
2002	3.36	4.07	3.89	3.80		3.90	3.93	
2003	5.49	6.66	6.37	6.00		6.40	6.32	
2004	5.90	6.87	6.62	6.35		6.48	6.45	
2005	8.60	8.58	8.43	8.48		8.35	8.12	
2006	6.75	7.16	6.87	6.59		6.67	6.45	
2007	6.95	6.65	6.41	6.35		6.18	6.25	
2008	8.85	8.15	7.90	8.10		8.07	8.10	
2009	3.95	4.20	3.95	3.90		3.87	4.05	
2010	4.40	4.15	3.90	3.85		3.96	3.90	
2011	4.00	3.70	3.50	3.75		3.56	3.30	
2012	2.75	2.45	2.25	2.25		2.31	2.25	
2013	3.75	3.20	3.00	3.00		3.10	2.90	3.08
2014	4.35	4.40	4.20	4.20	4.53	4.40	4.10	4.20
2015	2.60	2.80	2.55	2.55	3.00	2.70	2.00	2.10
2016	2.50	2.10	1.90	1.90	2.31	2.20	1.55	1.68
2017	2.95	2.40	2.15	2.15	2.83	2.35	1.75	1.88
2018	3.05	1.55	1.35	1.35	2.85	1.65	1.20	1.40
Forecast								
2019	3.00	1.85	1.65	1.65	2.85	1.75	1.25	1.40
2020	3.00	2.20	2.00	2.00	2.90	2.10	1.70	1.85
2021	3.15	2.55	2.35	2.35	3.00	2.45	2.05	2.21
2022	3.45	3.05	2.85	2.85	3.20	2.95	2.65	2.81
2023	3.60	3.20	3.00	3.00	3.35	3.10	2.80	2.96
2024	3.70	3.30	3.10	3.10	3.45	3.20	2.90	3.07
2025	3.75	3.35	3.10	3.10	3.50	3.20	2.85	3.02
2026	3.85	3.40	3.15	3.15	3.55	3.25	2.90	3.07
2027	3.90	3.45	3.20	3.20	3.65	3.30	2.95	3.13
2028	4.00	3.55	3.30	3.30	3.75	3.40	3.05	3.23
2029	4.05	3.60	3.35	3.35	3.80	3.45	3.10	3.28
2030	4.15	3.70	3.45	3.45	3.90	3.55	3.20	3.39
2031	4.25	3.75	3.50	3.50	3.95	3.65	3.25	3.44
2032	4.30	3.80	3.55	3.55	4.00	3.70	3.30	3.49
2033	4.40	3.90	3.65	3.65	4.10	3.80	3.40	3.60
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

(1) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the Crown royalty calculations.

CAPITAL COST MODEL

```
def capex_model(hz_length, prop_int, tvd, wells_in_pad, stage_spacing, base_equip_cost=375000, base_tie_in_cost=375000):
    base_drilling_cost = (tvd + 0.3 * hz_length) * 1000
    total_tonnage = hz_length * prop_int
    dollars_per_tonne_stage_count_factor = (60 / stage_spacing) ** (0.12)
    dollars_per_tonne = 80000 * dollars_per_tonne_stage_count_factor * total_tonnage ** (-0.5)
    base_completion_cost = total_tonnage * dollars_per_tonne
    pad_drilling_discount_factor = (wells_in_pad / 4) ** (-0.1)
    pad_completion_discount_factor = (wells_in_pad / 4) ** (-0.05)
    drilling_cost = base_drilling_cost * pad_drilling_discount_factor
    completion_cost = base_completion_cost * pad_completion_discount_factor
    equip_cost = base_equip_cost
    tie_in_cost = base_tie_in_cost

    return {'D': drilling_cost,
            'C': completion_cost,
            'E': equip_cost,
            'T': tie_in_cost,
            'Total': drilling_cost + completion_cost + equip_cost + tie_in_cost,
            'units': 'CAD'}
```